Ernest Orlando Lawrence Berkeley National Laboratory

Distributed Energy Resources Customer Adoption Model Technology Data

Ryan Firestone
Environmental Energy Technologies Division

January, 2004

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions and funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Distributed Energy Program of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098 and by the California Energy Commission, Public Interest Energy Research Program, under Work for Others Contract No. BG 99-396 (00).

Acknowledgments

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions and funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Distributed Energy Program of the U.S. Department of Energy (DOE) under Contract No. DE-AC03-76SF00098 and by the California Energy Commission (CEC), Public Interest Energy Research Program, under Work for Others Contract No. BG 99-396 (00). The author would like to thank program managers Pat Hoffman (DOE) and Mark Rawson (CEC).

The author would also like to thank the following people for their discussions on equipment, installation, and maintenance cost estimates. However, no costs used in the DER-CAM database come directly from any of these sources.

- Patrick Hale (Yazaki Energy Systems, Inc.)
- Gary Harbison (California Hydronics. Inc.)
- Tony Hynes (Bowman Power Systems, Inc.)
- Johan Niehaus (Southwest Photovoltaic Systems, Inc.)
- Rory Richardson (Bowman Power Systems, Inc.)
- Jennifer Straus (Powerlight Corporation)
- Kim Tan (Oakland Trane)
- Andrew Wang (Capstone Microturbine)

Additionally, the work and understanding herein builds on previous work and discussion at the Berkeley Lab, and the author would like to thank DER team members Owen Bailey, Emily Bartholomew, Jennifer Edwards, Kristina Hamachi LaCommare, and Chris Marnay.

Table of Contents

List of Tables

List of Figures

1. Introduction

The distributed energy resources customer adoption model (DER-CAM) is a software tool developed at the Berkeley Lab in which an economically optimal combined heat and power (CHP) DER system can be selected for a site, given its energy usage profiles, utility tariffs, and DER equipment options.

Based on the DER equipment research done by Berkeley Lab, a representative set of equipment options was created for use in DER-CAM. The data presented here are generalized across a broad range of technologies, and do not include modifications required to account for applicable subsidies and particular equipment options available at specific sites.

For DER-CAM and other DER studies, it is desirable to have a generic set of DER equipment data in the public domain, complete with documentation. The data set should be technology neutral and consistent.

This report details the updating of the DER-CAM technology database in early 2004, using the National Renewable Energy Laboratory (NREL) study, "Gas-Fired Distributed Energy Resource Technology Characterizations[1]" (Goldstein, 2003) as a starting point. The NREL Technology Characterizations contains technology data for fuel cells, microturbines, turbines, and reciprocating engines, including capital costs for electricity generation only and for CHP heating. Chapter 2 describes the parameters in the DER-CAM database and the procedures for converting the NREL Technology Characterization data into this format.

Additional data has been compiled to provide data on smaller (less than 100 kW) natural gas reciprocating engines, a 200 kW fuel cell without CHP, an additional (60 kW) microturbine, photovoltaics, and CHP for absorption cooling. This procedure is described in Chapter 3. The complete, updated DER-CAM technology database is presented in Chapter 4. Chapter 5 discusses further DER technology characterization research of immediate interest to the DER team at the Berkeley Lab.

[1] Herein referred to as the "NREL Technology Characterizations"

2. Description of DER-CAM Parameters

This chapter describes the parameters of the DER-CAM database and the procedures for converting data from the NREL Technology Characterizations for use in the DER-CAM database.

2.1 Rated Capacity (maxp)

Maxp is the rated maximum electrical output (kW) of the equipment.

2.2 Lifetime

Lifetime is the lifetime (year) of the equipment. No distinction is made between equipment life and financial life

2.3 Capital Costs (capcost)

Capcost include the costs of equipment, system design, and installation. When appropriate, generation equipment can be purchased

- without heat recovery capabilities
- with heat recovery for heating
- with heat recovery for heating and absorption cooling[2]

Capcost is expressed as the cost per kW of rated electrical capacity ($/kW).

2.4 Operation and Maintenance Fixed Costs (OMFix)

OMFix includes all fixed annual operation and maintenance costs ($/kW a), *excluding fuel costs*, of the equipment

2.5 Operation and Maintenance Variable Costs (OMVar)

OMVar includes all variable operation and maintenance costs ($/kWh), *excluding fuel costs*, of the equipment

2.6 Heat Rate (HeatR)

HeatR is the heat rate (kJ fuel/kWh) of the equipment. HeatR is related to electrical efficiency, μ_e, by Equation 1).

$$HeatR = \frac{3600 kJ / kWh}{\mu_e} \qquad \text{Equation 1}$$

[2] Absorption cooling requires the same heat exchanger for producing hot water (to drive the chiller) that heat recovery for heating requires. Therefore, a system capable of utilizing recovered heat for absorption cooling is also capable of utilizing recovered heat for heating.

HeatR is expressed with respect to the higher heating value (HHV) of natural gas (or other fuel) because the purchase price of natural gas as expressed in DER-CAM is with respect to the HHV. Heat rates and efficiencies are often specified by manufacturers with respect to the lower heating value (LHV) of natural gas[3].

2.7 Heat to Power Ratio (α)

α is the ratio of recoverable heat at maxp to maxp.

In DER-CAM, α is based on the waste heat energy content *prior to* conversion via a heat exchanger, referred to here as *recoverable* heat. The NREL Technology Characterizations specifies an electrical power-to-heat ratio based on the waste heat energy content *after* conversion via a heat exchanger, referred to here as *recovered* heat. To account for this difference, the Berkeley Lab assumes heat exchangers of 80% effectiveness. Thus, power-to-heat ratios from NREL are multiplied by 0.8 to correspond with the definition of α used in DER-CAM. The inverse of this modified power-to-heat ratio is the alpha used by DER-CAM (Equation 2).

$$\alpha = \left(\left(\frac{Power}{Heat} \right)_{NREL} \times HeatExchangerEffectiveness \right)^{-1} \qquad \text{Equation 2}$$

2.8 Conversion Efficiency for Recoverable Heat to Load Displacement (γ)

γ is an estimate of the portion of recoverable heat that is useful for displacing heating loads through heat exchangers or cooling loads via absorption chillers. γ for hot water and space heating loads is the heat exchanger effectiveness. DER-CAM currently assumes a value of 0.8 for γ for heat loads.

Cooling loads in DER-CAM are defined as the amount of electricity required to provide the desired amount of cooling, assuming a specified value for electric chiller efficiency. γ for absorption cooling is therefore the ratio of electrical cooling load displacement to recoverable heat. This value must incorporate the heat exchanger effectiveness as well as the relative performance of electric and absorption chillers as described in Equation 3, where COP_{abs} is the coefficient of performance[4] (COP) of an absorption chiller and $COP_{electric}$ is the coefficient of performance of an electric chiller.

$$\gamma_{abs} = Effectiveness_{HeatEx} * \frac{COP_{abs}}{COP_{electric}} \qquad \text{Equation 3}$$

[3] An average value for the HHV of natural gas is 38.3 MJ/m^3 while for the LHV it is 34.6 MJ/m^3 (ORNL, (1)). Thus, the ratio of LHV to HHV is 0.903. An electrical efficiency stated with respect to the LHV of natural gas can be multiplied by this ratio to determine the efficiency with respect to the HHV of natural gas.

[4] The coefficient of performance (COP) of a chiller is the ratio of heat removed by the chiller to energy (electricity or heat) provided to the chiller.

COP_{abs} has an assumed value of 0.65 for single-stage hot-water fired absorption chillers and $COP_{electric}$ has an assumed value of 4 for electric compression driven chillers[5]. Thus, γ_{abs} has a value of 0.13 for CHP absorption chillers.

2.9 Conversion Efficiency for Fuel to Load Displacement (β)

β is an estimate of the portion of fuel energy content that is useful for displacing heat loads via heat exchangers or cooling loads via absorption chillers. For heat loads, this is the boiler efficiency. DER-CAM currently assumes a value of 0.8 for β for heat loads and 0.13 for cooling loads. The lower value for cooling loads is because cooling loads in DER-CAM are expressed as the amount of electricity requested to provide the desired amount of cooling and cooling data is invariably expressed as electricity used by the air conditioner. Thus, β for absorption chillers must incorporate the ratio of fuel energy to useful heat as well as the relative performance of electric and absorption chillers, as discussed in Section 2.8. It is assumed that direct natural gas combustion can be used to supplement recovered heat in supplying the heat load to the absorption chiller. Because the heat exchanger effectiveness and boiler efficiency both have an assumed value of 0.8, β and γ have the same values.

2.10 β and γ Values

Table 1 presents the underlying assumptions used to generate β and γ values for DER-CAM. Table 2 presents the β and γ values used in DER-CAM.

Table 1: Underlying Assumptions Used For β and γ Values

Underlying Assumptions

Heat Exchanger Effectiveness	0.8
Boiler Efficiency	0.8
COP, absorption chiller	0.65
COP, electric chiller	4

[5] DER-CAM assumes that sites have electric chillers installed prior to DER considerations, and a COP of 4 is an approximation of chiller performance for units currently installed in the United States. Acutal COPs of electric chillers can vary widely by product and conditions of use such as temperature differential between hot inlet and cold outlet.

Table 2: β and γ Values Used In DER-CAM

	beta		***gamma***	
end-use	**formula**	**value**	**formula**	**value**
electricity-only	$\beta_{electric} = 0$	0	$\gamma_{electric} = 0$	0
cooling	$\beta_{abs} = Efficiency_{boiler} * \frac{COP_{abs}}{COP_{electric}}$	0.13	$\gamma_{abs} = Effectiveness_{HeatEx} * \frac{COP_{abs}}{COP_{electric}}$	0.13
space-heating	$\beta_{heating} = Efficiency_{boiler}$	0.8	$\gamma_{heating} = Effectiveness_{HeatEx}$	0.8
water-heating	$\beta_{heating} = Efficiency_{boiler}$	0.8	$\gamma_{heating} = Effectiveness_{HeatEx}$	0.8
naturalgas-only	$\beta_{naturalGas} = 1$	1	$\gamma_{naturalGas} = 0$	0

3. Data Not Provided From the NREL Technology Characterizations

The NREL Technology Characterizations does not cover all of the technology data required by DER-CAM. Capital costs for equipment coupled with absorption chillers and the performance and cost data for smaller (< 100 kW) natural gas reciprocating engines, a 60 kW microturbine, a 200kW fuel cell without CHP, and photovoltaics were estimated.

3.1 Natural Gas Engines Smaller Than 100 kW

The NREL Technology Characterizations did not consider natural gas fired reciprocating engines smaller than 100 kW. However, such equipment does exist and competes with microturbines, which are commercial in units as small as 30 kW. Therefore, small natural gas engine options are desirable for DER-CAM. Due to difficulties in acquiring manufacturer cost estimates for smaller prime-power natural gas engines, the NREL data was generalized and extrapolated to determine performance and cost estimates for natural gas engines of 30, 60, and 75 kW.

Figure 1 through Figure 3 illustrate the scatter plots and logarithmic curve fits[6] used to determine electrical efficiency, α (Alpha), capital costs, and maintenance costs for natural gas engines under 100 kW.

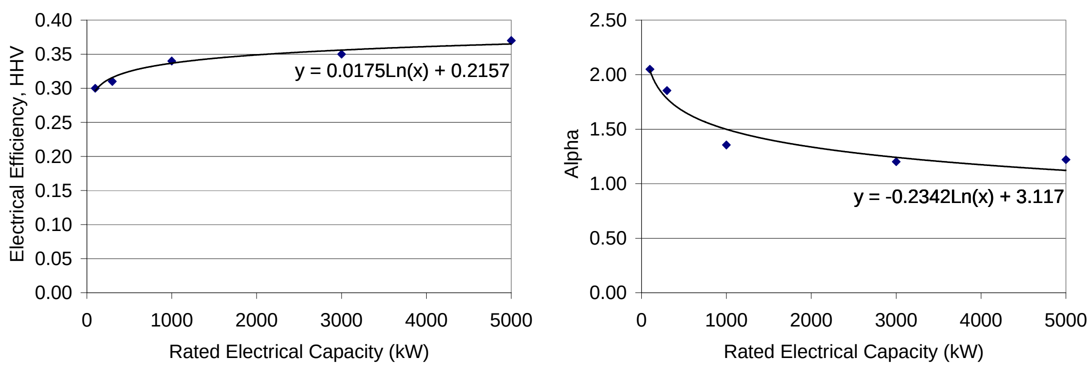

Figure 1: Scatter Plots of Natural Gas Engine Electrical Efficiency (left) and α (right) vs. Rated Electrical Capacity For Engines in NREL Technology Characterizations

[6] The choice of logarithmic curve fitting was based on empirical observation of collected data

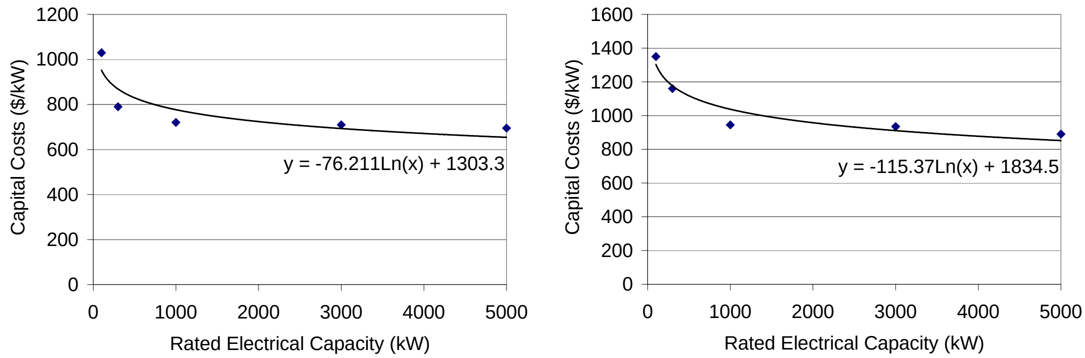

Figure 2: Scatter Plots of Natural Gas Engine Capital Costs Without Heat Recovery (left) and With Heat Recovery (right) vs. Rated Electrical Capacity For Engines in NREL Technology Characterizations

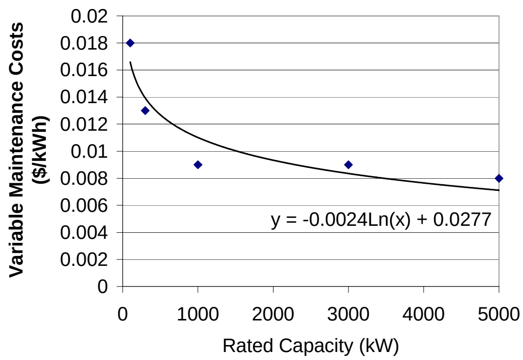

Figure 3: Scatter Plot of Natural Gas Engine Variable Maintenance Costs vs. Rated Electrical Capacity For Engines in NREL Technology Characterizations

From these curve fits, the technology data for small natural gas engines in Table 3 was derived. Consistent with larger natural gas engines, lifetimes of smaller engines were assumed to be 20 years and all maintenance costs are accounted for as variable maintenance costs.

Table 3: Small Natural Gas Engine Data

			Capital Costs ($/kW)		
Rated Electrical Capacity (kW)	Electrical Efficiency (HHV)	Alpha	Electricity Only	With Heat Recovery For Heating	O&M Variable Costs ($/kWh)
30	0.275	2.32	1044	1442	0.020
60	0.287	2.16	991	1362	0.018
75	0.291	2.11	974	1336	0.017

3.2 Fuel Cells Without Heat Recovery

Capital costs for the 200 kW fuel cell without heat recovery were not included in the NREL Technology Characterizations. The 200 kW fuel cell has an alpha value of 1.25, which corresponds to 250 kW of recoverable heat. Heat recovery equipment for fuel cells was assumed to be similar to heat recovery equipment for natural gas engines, therefore the capital costs for the 100 kW natural gas engine (205 kW of recoverable heat) were used to derive capital costs for heat recovery of the 200 kW fuel cell. The heat recovery equipment referred to here is for heating applications only (i.e. it does not include an absorption chiller).

The 100 kW natural gas engine has a total capital cost of $103,000 without heat recovery and $135,000 with heat recovery, meaning the incremental cost of including heat recovery is $32,000 for this system. This unit produces 205 kW of recoverable heat while running at rated capacity, and therefore the incremental cost of providing heat recovery is $156 per kW of recoverable heat. Assuming this cost is the same for the fuel cell with 250 kW of recoverable heat, the cost of heat recovery for heating for the fuel cell is $39,000 (or $195/kW). The default fuel cell system capital costs used in DER-CAM are therefore $5,200/kW for a system with heat recovery and $5,005/kW for a system without heat recovery.

3.3 60 kW Microturbines

Of the estimated 3,000 microturbines that had been installed worldwide cumulatively as of spring 2003, approximately 2,500 were manufactured by Capstone[7]. The Capstone 60 kW microturbine is a popular model and would most likely be one of the main purchase options for sites considering microturbines. Therefore, data on the Capstone's 60 kW C60 microturbine were added. Capital costs were derived from NREL Technology Characterization data for microturbines (Figure 4), using the curve fitting procedure described in Section 3.1.. Maintenance costs were assumed to consist of $0.015/kWh variable costs and no fixed costs, consistent with the NREL Technology Characterization microturbines. Electrical efficiency and alpha values were obtained from the Capstone C60 specification sheet[8]. Table 4 presents the derived data for a 60 kW microturbine.

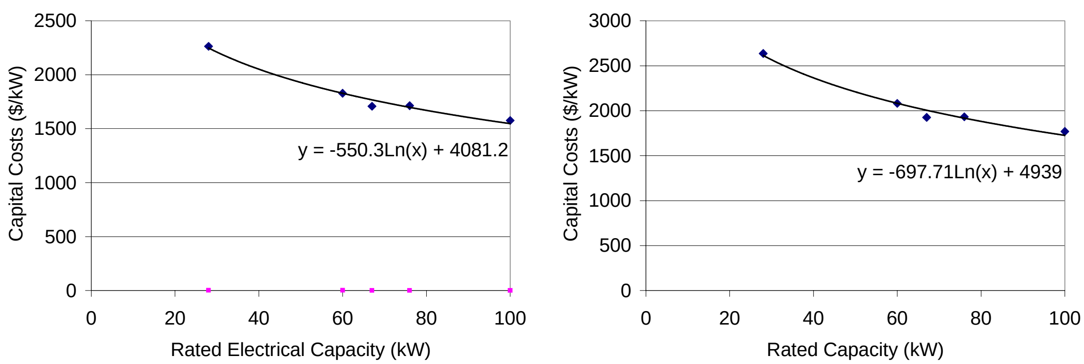

Figure 4: Scatter Plots of Microturbine Capital Costs Without Heat Recovery (left) and With Heat Recovery (right) vs. Rated Electrical Capacity For Microturbines in NREL Technology Characterizations

---

[7] Hynes, 2003. This presentation and others from the DG and CHP for Federal Facilities workshop in Newport Beach, CA are available online at http://www.energetics.com/femp/la.html
[8] Available from the Capstone website at http://www.capstoneturbine.com

Table 4: 60 kW Microturbine Data

Rated Electrical Capacity (kW)	Electrical Efficiency (HHV)	Alpha	*Capital Costs ($/kW)* Electricity Only	With Heat Recovery For Heating	O&M Variable Costs ($/kWh)
60	0.25	2.24	1828	2082	0.015

3.4 Photovoltaics

Based on conversations with photovoltaic system providers, Equation 4 was derived to estimate the capital costs of 10 kW, 25 kW, 50 kW, and 100 kW systems

$$\mathrm{CapCosts(maxp)} = (\mathrm{SysCapCosts} + \mathrm{InvRepl} + \mathrm{InstVar}) \times \mathrm{maxp} + \mathrm{InstFix}$$

Equation 4

where

- *CapCosts(maxp)* is the capital costs ($) of a system of size maxp.
- *SysCapCosts* is the capital costs ($/kW) due to purchase of the system
- *InvRepl* is the net present value ($/kW) of a replacement inverter purchased after 15 years[9]
- *InstVar* is the variable costs ($/kW) of system design and installation
- *InstFix* is the fixed costs ($) of system design and installation

Table 5 summarizes these parameter values and Table 6 presents capital costs for the system sizes listed above. The lifetime of photovoltaic systems is assumed to be 30 years, including an inverter replacement after 15 years.

Table 5: Photovoltaic Capital Cost Parameters

SysCapCosts ($/kW)	6000
InvRepl ($/kW)	340 [1]
InstVar ($/kW)	1400 [2]
InstFix ($)	10000 [2]

1: Based on inverter costs of $1000/kW and a discount rate of 7.5%

2: Installation costs can vary by a factor of two depending on the site and the type of mounting.

[9] Photovoltaics have a lifetime of 30 years, while inverters have a lifetime of 15 years.

Table 6: Total Capital Costs For Photovoltaic Systems

Maxp (kW)	Capital Costs ($)	Capital Costs ($/kW)
10	87,400	8740
25	203,500	8140
50	397,000	7940
100	784,000	7840

The only maintenance required of photovoltaic systems is cleaning the panels. Operation and maintenance costs are assumed to be $12/kW annually[10].

3.5 Absorption Chiller Costs

The NREL Technology Characterizations does not provide data on absorption chiller systems. Therefore, capital cost and maintenance cost estimates of hot water fired, single stage indirect absorption chillers were required.

3.5.1 Absorption Chiller Capital Costs

The total installed costs of absorption chillers includes design, engineering, installation, and equipment costs of the chiller, cooling tower, and electrical and plumbing systems and connections. These costs can vary widely for similarly sized units based on the manufacturer, the location specific freight costs, the site-specific installation needs, application and location specific cooling tower design, etc.

Literature review and conversations with manufactures and distributors have been used to determine the range of costs for waste-heat driven chillers. The costs and performance estimates used here are for stand-alone chiller units, not integrated generator/chiller packages that are currently being commercialized. Integrated packages may offer some economic savings and performance improvements.

In addition to the chiller/cooling tower system, a heat exchanger is required for transfer of recoverable heat to an acceptable medium and temperature for the chiller. It is assumed that this heat exchanger is comparable to that used for heat recovery for heating, so that the capital costs of including absorption chilling with an electricity generation unit is added to the cost of an electricity generation unit with heat recovery for heating. This implies that generation units with absorption chillers can also be configured to provide heat recovery for heating at no additional cost.

Figure 5 presents scatter plots of absorption chiller cost ($/kW chilling) versus chiller capacity (kW chilling) from five studies[11] and the curve fits based on this data used to

[10] based on a power density of 100 W/m^2, a cleaning speed of 1 person-day per 2000 m^2, and labor and material costs of $200/person-day.
[11] Bailey, 2002; Farrar, 2003; LeMar, 2002; Resource Dynamics Corporation, 2003; and research conducted by the author of this report.

generate absorption chiller costs for DER-CAM. Two logarithmic curve fits were used, one for chillers of capacity less than 1,000 kW and one for chillers of capacity larger than 1,000 kW. Table 7 displays these results.

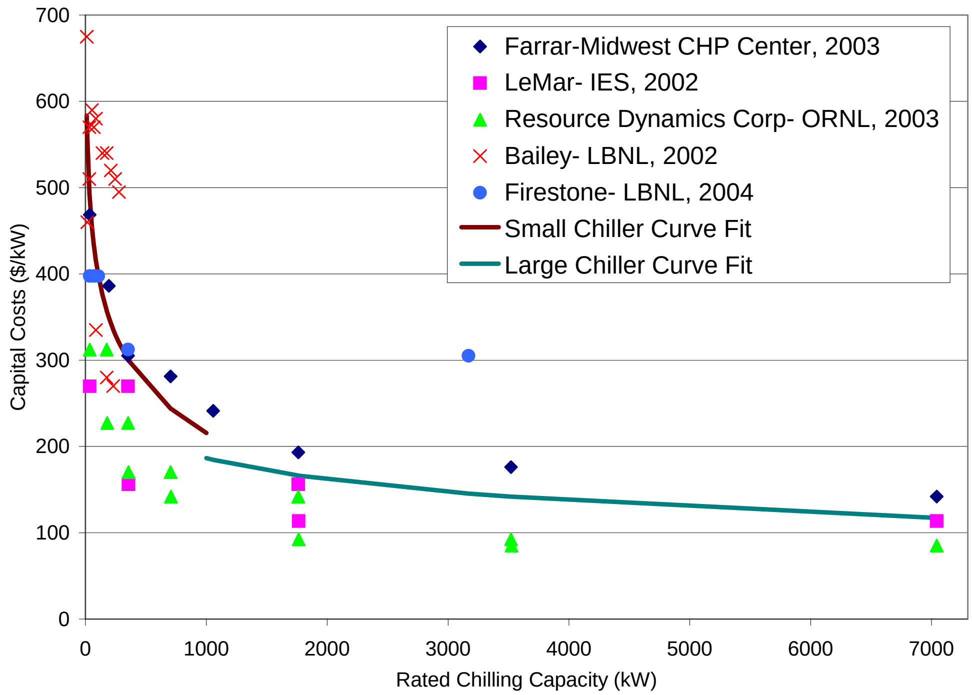

Figure 5: Capital Costs of Hot Water Fired Indirect, Single Stage Absorption Chillers Versus Chiller Capacity

Table 7: Logarithmic Curve Fits For Absorption Chiller Capital Costs

	a*	b*
Small Chiller Curve Fit**	-81.552	778.95
Large Chiller Curve Fit**	-35.469	431.41

***** where ***CapitalCost($/kW chilling) = a*ln(Chilling Capacity (kW)) + b***

**For these curve fits, chillers with cooling capacity less than 1000 kW are considered "Small" and those with cooling capacity greater than 1000 kW are considered "Large".

3.5.2 Absorption Chiller Maintenance Costs

A similar procedure was used to estimate annual maintenance costs ($/kW rated cooling capacity) based on collected data as shown in Figure 6 and Table 8 using those sources that provided maintenance cost data[12], although only one curve fit was used for the entire chiller capacity range. Maintenance costs for absorption chillers with cooling capacities larger than 7,000 kW were assumed to be $3.10/kW a, the curve fit value at 7,000 kW.

[12] Farrar, 2003; LeMar, 2002; and Resource Dynamics Corporation, 2003

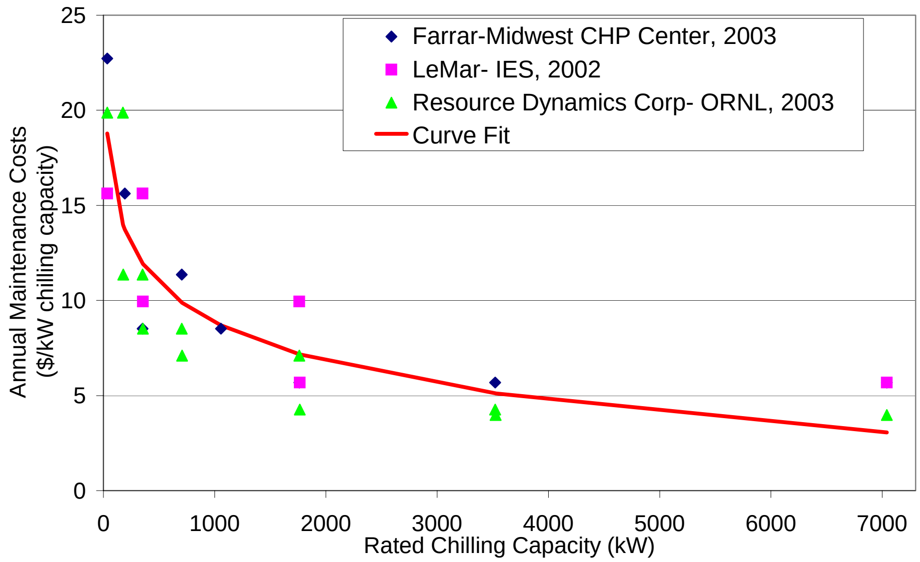

Figure 6: Annual Maintenance Costs of Hot Water Fired Indirect, Single-Stage Absorption Chillers Versus Chiller Capacity

Table 8: Logarithmic Curve Fit For Absorption Chiller Maintenance Costs

	a*	b*
Curve Fit	-2.9658	29.34

* where ***AnnualMaintenanceCost($/kW chilling) = a*ln(Chilling Capacity (kW)) + b***

3.5.3 Absorption Chiller Performance

DER-CAM assumes a universal COP_{abs} of 0.65 for all absorption chillers. The structure of DER-CAM allows for only one COP for all absorption chillers, although realistically chillers with less than 300 kW rated cooling tend to have COPs closer to 0.60 while larger chillers can have COPs closer to 0.70. Absorption chillers tend to maintain their rated COPs even at part loads. Thus, the single COP_{abs} assumption is reasonable. It should be noted that in turbines and microturbines, all recoverable heat is in the form of high temperature exhaust, while in reciprocating engines recoverable heat is present in both the high temperature exhaust and lower temperature radiator loop, and in fuel cells, recoverable heat may be present in either form depending on the temperature of fuel cell stacks and the need for a cooling loop[13].

While hot water fired absorption chillers (single-effect, indirect) could be used for all of these applications, better performance could be achieved from exhaust fired absorption chillers (single or double effect, indirect fired) for turbines and microturbines. Packaged

[13] Turbine exhaust is typically approximately 500˚C, microturbine exhaust is typically approximately 260˚C. Natural gas engine exhaust is typically in the range of 300˚C to 500˚C. Natural gas engine radiator loop temperatures are typically 85˚C to 95˚C.

CHP systems that include microturbines and exhaust fired absorption chillers are currently being commercialized.

3.5.4 Absorption Chiller Lifetime

Absorption chillers have an assumed lifetime of 20 years. Natural gas engines and turbines also have a lifetime of 20 years, while fuel cells and microturbines have an assumed lifetime of 10 years. Absorption chiller capital costs were adjusted to account for the shorter system lifetime of fuel cells and microturbines. Absorption chiller capital costs were first amortized over the lifetime of the equipment (20 years) as detailed in Equation 5

$$AmortizedCost_{abs} = CapCost_{abs} \times \left(\frac{i}{1-(1+i)^{-AbsLifetime}} \right) \qquad \text{Equation 5}$$

where

- $AmortizedCost_{abs}$ is the amortized annual cost of the absorption chiller over its lifetime
- $CapCost_{abs}$ is the upfront capital costs of the absorption chiller
- i is the interest rate
- *AbsLifetime* is the lifetime of the absorption chiller

The net present value of these uniform payments over the lifetime of the generation equipment (10 years) was then calculated to determine the adjusted capital costs, as detailed in Equation 6

$$AdjustedCapCost_{abs} = AmortizedCost_{abs} \times \left(\frac{1-(1+i)^{-EquipLifetime}}{i} \right) \qquad \text{Equation 6}$$

where

- *EquipLifetime* is the lifetime of the electricity generation equipment that the absorption chiller is coupled to

Thus, the adjusted capital costs of absorption chillers with lifetimes different than the electricity generation equipment they are coupled to can be calculated from Equation 7.

$$AdjustedCapCost_{abs} = CapCost_{abs} \times \left(\frac{1-(1+i)^{-EquipLifetime}}{1-(1+i)^{-AbsLifetime}} \right) \qquad \text{Equation 7}$$

For electricity generation equipment lifetimes of 10 years, absorption chiller equipment lifetimes of 20 years, and an interest rate of 7.5%, Equation 8 describes the adjustment calculation.

$$AdjustedCapCost_{abs} = CapCost_{abs} \times 0.67 \qquad \text{Equation 8}$$

3.5.5 Sizing Absorption Chillers to Generation Equipment

DER-CAM equipment options consist of electrical generation devices with or without heat recovery for absorption chilling. Therefore, an absorption chiller must be sized to each generation device to determine the additional costs of absorption chilling. To do this, a heat exchanger efficiency of 0.80 was used to determine the amount of useful waste heat from each generation device at rated capacity. Assuming a COP_{abs} of 0.65, the amount of cooling (kW) possible with this waste heat (kW) was determined by Equation 9.

$$\text{Cooling} = \text{WasteHeat} \times \text{COP}_{\text{abs}} \qquad \text{Equation 9}$$

This cooling capacity was then used to determine the capital costs and maintenance costs for an absorption chiller of that capacity using the results of Table 7 and Table 8.

3.5.6 Absorption Chiller Costs For DER-CAM

Table 9 presents the absorption chiller cost calculations, the results of which are used in the DER-CAM database.

Table 9: Absorption Chiller Cost Calculations

							Capital Cost Calculations						*Maintenance Cost Calculations*		
		Rated Capacity, maxp (kW)	**Lifetime (years)**	**Capital Costs Per Electrical Capacity, Heat Recovery For Heating ($/kW)**	**Alpha For CHP Units**	**Recoverable Heat (kW) at Rated Capacity**	**Chiller Capacity (kW)**	**Capital Costs of Abs. Chilling ($/kW chilling)**	**Total Capital Costs of Abs. Chilling ($)**	**Capital Cost of Abs. Chilling Per Electrical Capacity ($/kW)**	**Capital Costs of Abs. Chilling, Adjusted To Equipment Lifetime ($/kW)**	**Capital Cost of Electricity Generation Equipment and Abs. Chiller ($/kW)**	**Annual Maintenance Costs ($/kW chilling)**	**Total Annual Maintenance Costs ($)**	**Annual Maintenance Costs Per Electrical Capacity ($/kW)**
Fuel Cells	**FC-200**	200	10	5200	1.25	250	130	382	49659	248	166	5366	15	1938	9.7
Gas Turbines	**GT-01000**	1000	20	1910	2.45	2451	1275	178	226602	227	227	2137	8	10366	10.4
	GT-05000	5000	20	1024	1.84	9191	4779	131	625692	125	125	1149	4	20138	4.0
	GT-10000	10000	20	928	1.71	17123	8904	109	969171	97	97	1025	3	27603	2.8
	GT-25000	25000	20	800	1.32	32895	17105	86	1465727	59	59	859	3	53026	2.1
	GT-40000	40000	20	702	1.17	46729	24299	73	1779595	44	44	746	3	75327	1.9
Microturbines	**MT-028**	28	10	2636	2.40	67	35	489	17115	611	410	3046	19	658	23.5
	MT-060	60	10	2082	2.24	134	70	433	30234	504	338	2420	17	1170	19.5
	MT-067	67	10	1926	1.79	120	62	442	27504	411	275	2201	17	1063	15.9
	MT-076	76	10	1932	1.98	151	78	423	33186	437	293	2225	16	1286	16.9
	MT-100	100	10	1769	1.71	171	89	413	36761	368	246	2015	16	1427	14.3
Natural Gas Engines	**NG-030**	30	20	1442	2.32	70	36	486	17599	587	587	2029	19	677	22.6
	NG-060	60	20	1362	2.16	130	67	436	29354	489	489	1851	17	1136	18.9
	NG-075	75	20	1336	2.11	158	82	419	34503	460	460	1796	16	1338	17.8
	NG-0100	100	20	1350	2.05	205	107	398	42446	424	424	1774	15	1651	16.5
	NG-0300	300	20	1160	1.85	556	289	317	91626	305	305	1465	13	3625	12.1
	NG-1000	1000	20	945	1.36	1355	705	244	172037	172	172	1117	10	6969	7.0
	NG-3000	3000	20	935	1.20	3605	1875	164	308113	103	103	1038	7	13102	4.4
	NG-5000	5000	20	890	1.22	6104	3174	121	385375	77	77	967	5	17227	3.4

4. The Updated DER-CAM Technology Data Base

The DER-CAM technology database was constructed, starting with the data provided by the NREL Technology Characterizations, and then completed using the results of Chapter 3. Table 10 presents the DER-CAM technology database. β and γ values used in DER-CAM can be found in Section 2.10, Table 2.

DER-CAM is currently used to evaluate sites with peak electric loads of approximately 1 MW or less. For such studies the gas turbines and natural gas engines larger than 1 MW in Table 10 need not be considered.

Table 10: DER-CAM Technology Database

Color Key
Data From NREL Technology Characterizations
Remaining DER-CAM Data Requirements
Not Applicable

				capcost ($/kW)									
		maxp (kW)	**lifetime (years)**	**Electricity Only**	**CHP for Heating**	**CHP for Heating and Cooling**	**OMFix with Abs. Cooling ($/kW a)**	**OMFix without Abs. Cooling ($/kW a)**	**OMVar ($/kWh)**	**HeatR (kJ/kWh)**	**Fuel***	**Type****	**Alpha for CHP units**
Fuel Cells	**FC-200**	200	10	5005	5200	5366	9.69	0	0.029	10000	1	1	1.25
Gas Turbines	**GT-01000**	1000	20	1403	1910	2137	10.37	0	0.0096	16438	1	1	2.45
	GT-05000	5000	20	779	1024	1149	4.03	0	0.0059	13284	1	1	1.84
	GT-10000	10000	20	716	928	1025	2.76	0	0.0055	12414	1	1	1.71
	GT-25000	25000	20	659	800	859	2.12	0	0.0049	10496	1	1	1.32
	GT-40000	40000	20	592	702	746	1.88	0	0.0042	9730	1	1	1.17
Microturbines	**MT-028**	28	10	2263	2636	3046	23.49	0	0.015	15929	1	1	2.40
	MT-060	60	10	1828	2082	2420	19.50	0	0.015	14400	1	1	2.24
	MT-067	67	10	1708	1926	2201	15.87	0	0.015	14286	1	1	1.79
	MT-076	76	10	1713	1932	2225	16.92	0	0.015	14876	1	1	1.98
	MT-100	100	10	1576	1769	2015	14.27	0	0.015	13846	1	1	1.71
Natural Gas Engines	**NG-030**	30	20	1044	1442	2029	22.56	0	0.02	13080	1	1	2.32
	NG-060	60	20	991	1362	1851	18.93	0	0.018	12528	1	1	2.16
	NG-075	75	20	974	1336	1796	17.84	0	0.017	12360	1	1	2.11
	NG-0100	100	20	1030	1350	1774	16.51	0	0.018	12000	1	1	2.05
	NG-0300	300	20	790	1160	1465	12.08	0	0.013	11613	1	1	1.85
	NG-1000	1000	20	720	945	1117	6.97	0	0.009	10588	1	1	1.36
	NG-3000	3000	20	710	935	1038	4.37	0	0.009	10286	1	1	1.20
	NG-5000	5000	20	695	890	967	3.45	0	0.008	9730	1	1	1.22
Photovoltaics	**PV-010**	10	30	8740				12	0		0	1	
	PV-025	25	30	8140				12	0		0	1	
	PV-050	50	30	7940				12	0		0	1	
	PV-100	100	30	7840				12	0		0	1	

* 0=solar radiation, 1=natural gas, 2= diesel (although no diesel equipment is considered here, DER-CAM is currently capable of considering such equipment)

** Equipment can be grouped into three arbitrary categories. Categories can then be subsidized differentially in DER-CAM (but subsidies cannot be specified in the current version of the Automation Manager)

5. Further Research

This section outlines several areas for DER-CAM technology data improvements that are of immediate interest to the Berkeley Lab DER team.

5.1 Cost/Performance Tradeoffs

DER-CAM considers only one option of any technology of given size. However, for natural gas engines, turbines, photovoltaics, heat exchangers, and absorption chillers, equipment of the same rated capacity is available from multiple manufacturers and customers may be able to make cost/performance tradeoff decisions. It is of interest to Berkeley Lab to expand The DER-CAM database to include more than one option per equipment size for certain technologies.

5.2 Additional Heating and Cooling Technologies

There are several DER heating and cooling options currently not considered in DER-CAM, including

- adsorption chillers
- exhaust fired, indirect, double effect absorption chillers
- direct fired, thermally activated cooling technologies (currently only limited consideration)
- desiccant dehumidifiers
- heat pumps
- solar thermal heating and/or cooling

5.3 Part-load Performance

DER-CAM currently assumes that performance data, which is based on performance at rated capacity, does not change for part-load operation. Modeling efficiency reductions at part-load would improve the accuracy of DER-CAM estimates.

5.4 Reliability

DER-CAM currently assumes that DER equipment is 100% available. However, scheduled and unscheduled maintenance requirements invalidate this assumption. While it is a considerable challenge to obtain DER equipment availability data and to characterize it, reliability can have a significant effect on non-linear energy costs such as electricity demand charges (Firestone, 2004).

5.5 Emissions

DER-CAM currently calculates carbon emissions based on fuel consumption. DER emissions of interest -including CO, NOx, SOx, particulate matter (PM), and volatile organic compounds (VOC)- could be characterized and their quantities calculated by DER-CAM.

References

Bailey, O., B. Ouaglal, E. Bartholomew, C. Marnay, and N. Bourassa. 2002. "An Engineering-Economic Analysis of Combined Heat and Power Technologies in a µGrid Application" Berkeley, CA: Lawrence Berkeley National Laboratory report LBNL-50023.

Farrar, L. 2003. "Spreadsheet for Evaluating Economics of CHP Systems" for the Midwest CHP Application Center. Available at http://www.bchp.org/library-tools.html.

Firestone, R., and C. Marnay. 2004. "Energy Manager Design for µGrids" Berkeley, CA: Lawrence Berkeley National Laboratory, In press.

Goldstein, L, B. Headman, D. Knowles, S.I. Freedman, R. Woods, T. Schweizer. 2003. "Gas-Fired Distributed Energy Resource Technology Characterizations" Golden, CO: National Renewable Energy Laboratory report NREL/TP-620-34783.

Hynes, Tony. 2003. "DG & CHP Technologies: an overview; Microturbines" a presentation at the DG & CHP in Federal Facilities workshop, Newport Beach, CA, May 2003.

LeMar, P. 2002. "Integrated Energy Systems (IES) for Buildings: A Market Assessment (Final Report)" prepared by Resource Dynamics Corporation, Vienna, VA for Oak Ridge National Laboratory, Oak Ridge, TN, report ORNL/SUB/409200.

ORNL (Oak Ridge National Laboratory). (1). "Bioenergy Conversion Factors", http://bioenergy.ornl.gov/papers/misc/energy_conv.html

Resource Dynamics Corporation. 2003. "Cooling, Heating, and Power for Industry: A Market Assessment" Vienna, VA. Prepared for Oak Ridge National Laboratory, Oak Ridge, TN.